Description

DUAL GAS FACILITY

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation of U.S. application serial number 10/384,156 filed on March 7, 2003, which is a continuation-in-part of application serial number 10/246,954 filed on September 18, 2002 which claims priority of U.S. provisional patent application 60/342,157 filed December 19, 2001.

BACKGROUND OF INVENTION

[0002] Much of the natural gas used in the United States is produced along the Gulf Coast. There is an extensive pipeline network both offshore and onshore that transports this natural gas from the wellhead to market. In other parts of the world, there is also natural gas production, but sometimes there is no pipeline network to transport the gas to market. In the industry, this sort of natural gas is often referred to as "stranded" because there is no ready market or pipeline connection. As a result, this stranded gas that

is produced concurrently with crude oil is often burned at a flare. This is sometimes referred to as being "flared off."

[0003] Different business concepts have been developed to more effectively utilize stranded gas. One such concept is construction of a petrochemical plant near the source of natural gas to use the gas as a feedstock for the plant. Several ammonia and urea plants have been constructed around the world for this purpose.

[0004] Another approach is to liquefy the natural gas at or near the source and to transport the LNG via ship to a receiving terminal. At the LNG receiving facility, the LNG is offloaded from the transport ship and stored in cryogenic tanks located onshore. At some point, the LNG is transferred from the cryogenic storage tanks to a conventional vaporizer system and gasified. The gas is then sent to market via a pipeline. At the start of this process, liquefaction may consume 9-10% of the LNG by volume. At the end of the process, the gasification may consume an additional 2-3% of the LNG by volume. To the best of Applicants knowledge, none of the existing conventional LNG facilities that use vaporizer systems thereafter store the resulting gas in salt caverns. Rather, the conventional LNG facilities with vaporizers transfer all of the resulting gas to

a pipeline for transmission to market.

[0005] Currently there are more than 100 LNG transport ships in service worldwide and more are on order. LNG transport ships are specifically designed to transport the LNG as a cryogenic liquid at or below -250°F and near or slightly above atmospheric pressure. Further, the ships run on the LNG and are counter-flooded to maintain a constant draft of about 40 feet. The LNG ships currently in service vary in size and capacity, but some hold about 3 billion cubic feet of gas (Bcf) (approx. 840,000 barrels) or more. Some of the ships of the future may have even greater capacity and as much as 5 Bcf. One of the reasons LNG is transported as a liquid is because it takes less space.

[0006] There are a number of LNG facilities around the world. In the U.S., two LNG receiving facilities are currently operational (one located in Everett, Massachusetts and one located south of Lake Charles, Louisiana) and two are being refurbished (one located in Cove Point, Maryland and one located at Elba Island, Georgia). Construction of additional LNG facilities in the U.S. has been announced by several different concerns.

[0007] The LNG receiving facilities in the U.S. typically include of-floading pumps and equipment, cryogenic storage tanks

and a conventional vaporizer system to convert the LNG into a gas. The gas may be odorized using conventional equipment before it is transmitted to market via a pipeline. LNG terminals are typically designed for peak shaving or as a base load facility. Base load LNG vaporization is the term applied to a system that requires almost constant vaporization of LNG for the basic load rather than periodic vaporization for seasonal or peak incremental requirements for a natural gas distribution system. At a typical base load LNG facility, a LNG ship will arrive every 3–5 days to offload the LNG. The LNG is pumped from the ship to the LNG storage tank(s) as a liquid (approx.−250°F) and stored as a liquid at low-pressure (about one atmosphere). It typically may take 12 hours or more to pump the LNG from the ship to the cryogenic storage tanks onshore.

[0008] LNG transport ships may cost more than $100,000,000 to build. It is therefore expedient to offload the LNG as quickly as possible so the ship can return to sea and pick up another load. A typical U.S. LNG base load facility will have three or four cryogenic storage tanks with capacities that vary, but are in the range of 250,000–400,000 barrels each. Many of the current LNG ships have a capacity

of approximately 840,000 barrels. It therefore will take several cryogenic tanks to hold the entire cargo from one LNG ship. These tanks are not available to receive LNG from another ship until they are again mostly emptied.

[0009] Conventional base load LNG terminals are continuously vaporizing the LNG from the cryogenic tanks and pumping it into a pipeline for transport to market. So, during the interval between ships (3–5 days), the facility converts the LNG to gas (referred to as regasification, gasification or vaporization) which empties the cryogenic tanks to make room for the next shipment. The LNG receiving and gasification terminal may produce in excess of a billion cubic feet of gas per day (BCFD). In summary, transport ships may arrive every few days, but vaporization of the LNG at a base load facility is generally continuous. Conventional vaporizer systems, well known to those skilled in the art, are used to warm and convert the LNG to usable gas. The LNG is warmed from approximately –250°F in the vaporizer system and converted from liquid phase to usable gas before it can be transferred to a pipeline. Unfortunately, some of the gas is used as a heat source in the vaporization process, or if ambient temperature fluids are used, very large heat exchangers are required. There is a need

for a more economical way to convert the LNG from a cold liquid to usable gas.

[0010] LNG cryogenic storage tanks are expensive to build and maintain. Further, the cryogenic tanks are on the surface and present a tempting terrorist target. There is therefore a need for a new way to receive and store LNG for both base load and peak shaving facilities. Specifically, there is a need to develop a new methodology that eliminates the need for the expensive cryogenic storage tanks. More importantly, there is a need for a more secure way to store huge amounts of flammable materials.

[0011] There are many different types of salt formations around the world. Some, but not all of these salt formations are suitable for cavern storage of hydrocarbons. For example, "domal" type salt is usually suitable for cavern storage. In the U.S., there are more than 300 known salt domes, many of which are located in offshore territorial waters. Salt domes are also known to exist in other areas of the world including Mexico, Northeast Brazil and Europe. Salt domes are solid formations of salt that may have a core temperature of 90°F or more. A well can be drilled into the salt dome and fresh water can be injected through the well into the salt to create a cavern. Salt cavern storage of

hydrocarbons is a proven technique that is well established in the oil and gas industry. Salt caverns are capable of storing large quantities of fluid. Salt caverns have high sendout capacity and most important, they are very, very secure. For example, the U.S. Strategic Petroleum Reserve now stores approximately 600,000,000 barrels of crude oil in salt caverns in Louisiana and Texas, i.e., at Bryan Mound, Texas.

[0012] When fresh water is injected into domal salt, it dissolves thus creating brine, which is returned to the surface. The more fresh water that is injected into the salt dome, the larger the cavern becomes. The tops of many salt domes are often found at depths of less than 1500 feet. A salt cavern is an elongate chamber that may be up to 1,500 feet in length and have a capacity that varies between 3-15,000,000 barrels. The largest is about 40 million barrels. Each cavern itself needs to be fully surrounded by the salt formation so nothing escapes to the surrounding strata or another cavern. Multiple caverns will typically be formed in a single salt dome. Presently, there are more than a 1,000 salt caverns being used in the U.S. and Canada to store hydrocarbons including the aforementioned crude oil stored in the Strategic Petroleum Reserve.

Sixty or more of these salt caverns are being used to store natural gas.

[0013] Two different conventional techniques are used in salt cavern storage—compensated and uncompensated. In a compensated cavern, brine or water is pumped into the bottom of the salt cavern to displace the hydrocarbon or other product out of the cavern. The product floats on top of the brine. When product is injected into the cavern, the brine is forced out. Hydrocarbons do not mix with the brine making it an ideal fluid to use in a compensated salt cavern. In an uncompensated storage cavern, no displacing liquid is used. Uncompensated salt caverns are commonly used to store natural gas that has been produced from wells. High-pressure compressors are used to inject the natural gas in an uncompensated salt cavern. Some natural gas must always be left in the cavern to prevent cavern closure due to salt creep. The volume of gas that must always be left in an uncompensated cavern is sometimes referred to in the industry as a "cushion." This gas provides a minimum storage pressure that must be maintained in the cavern. Again, to the best of Applicants knowledge, none of the present LNG receiving facilities take the LNG from the tankers, vaporize it and then store

the resulting gas in salt caverns.

[0014] Uncompensated salt caverns for natural gas storage preferably operate in a temperature range of approximately +40°F to +140°F and pressures of 1500 to 4000 psig. If a cryogenic fluid at sub-zero temperature is pumped into a cavern, thermal fracturing of the salt may occur and degrade the integrity of the salt cavern. For this reason, LNG at very low temperatures cannot be stored in conventional salt caverns. If a fluid is pumped into a salt cavern and the fluid is above 140°F it will encourage creep and decrease the volume of the salt cavern.

[0015] U.S. Patent No. 5,511,905 is owned by the assignee of the present application. William M. Bishop is listed as a joint inventor on the present application and the '905 patent. This prior art patent discloses warming of LNG with brine (at approximately 90°F) using a heat exchanger in a compensated salt cavern. This prior patent teaches storage in the dense phase in the compensated salt cavern. The '905 Patent does not disclose use of an uncompensated salt cavern. The '905 Patent also discloses that cold fluids may be warmed using a heat exchanger at the surface. The surface heat exchanger might be used where the cold fluids being offloaded from a tanker are to be heated for

transportation through a pipeline. The brine passing through the surface heat exchanger could be pumped from a brine pond rather than the subterranean cavern.

[0016] U.S. Patent No. 6,298,671 is owned by BP Amoco Corporation and is for a Method for Producing, Transporting, Offloading, Storing and Distributing Natural Gas to a Marketplace. The patent teaches production of natural gas from a first remotely located subterranean formation, which is a natural gas producing field. The natural gas is liquefied and shipped to another location. The LNG is re-gasified and injected into a second subterranean formation capable of storing natural gas which is a depleted or at least a partially depleted subterranean formation which has previously produced gas in sufficient quantities to justify the construction of a system of producing wells, gathering facilities and distribution pipelines for the distribution to a market of natural gas from the subterranean formation. The patent teaches injection of the re-gasified natural gas into the depleted or partially depleted natural gas field at temperatures above the hydrate formation level from 32°F. to about 80°F and at pressures of from about 200 to about 2500 psig. This patent makes no mention of a salt cavern. This patent makes no mention of

dense phase or the importance thereof. Furthermore, there are limitations on the injection and send out capacity of depleted and partially depleted gas reservoirs that are not present in salt cavern storage. In addition, temperature variances between the depleted reservoir and the injected gas create problems in the depleted reservoir itself that are not present in salt cavern storage. For all of these many reasons, salt caverns are preferred over cryogenic storage tanks or depleted gas reservoirs for use in a modern LNG facility.

[0017] Salt cavern natural gas storage is known and utilized between natural gas production facilities and natural gas markets to provide a buffer to swings in supply of natural gas and to swings in demand for natural gas. Swings in supply from gas production wells can be caused by weather phenomenon such as freezes or hurricanes or in the normal maintenance associated with natural gas production facilities. Swings in natural gas demand can be weather related such as demand for heating in cold weather or in demand for electricity generated from natural gas fueled generators. Salt cavern storage of natural gas is widely known as an excellent technology to accommodate very large demand increases in natural gas be-

cause of the ability of caverns to deliver large amounts of natural gas to pipelines on very short notice. The U.S. on average consumes about 60 billion cubic feet per day (Bcf/D) of natural gas but in peak demand periods can consume in excess of 115 Bcf/D. Natural gas storage is used to accommodate that wide variation in demand. There is over 3 trillion cubic feet (TCF) of natural gas storage capacity in the US of which about 95% is storage of natural gas in depleted reservoirs and aquifers and the remaining 5% in salt caverns. While salt caverns make up only about 5% of the storage capacity they provide more than 14% of the delivery capacity illustrating that salt caverns have much higher deliverability than other forms of storage. Salt caverns are characterized as having very high deliverability instantaneously available to be delivered to the pipeline grid.

[0018] The U.S. has the most comprehensive energy infrastructure in the world. The U.S. is the largest energy consuming nation in the world and there are projections that the demand for natural gas and the swings in that demand will increase in the future. There is an extensive pipeline network both offshore and onshore that transports this natural gas from the wellhead to market. Much of the nat-

ural gas used in the United States is produced along the Gulf Coast, where there is an abundance of natural gas pipeline distribution networks in proximity to navigable waters. An abundance of natural gas pipeline networks is sometimes referred to as the natural gas infrastructure.

[0019] Currently the U.S. consumes more natural gas than it produces. The shortfall in supply is largely made up by pipeline imports from Canada. Only about 1% of the current U.S. natural gas demand is supplied by imported LNG. However there are projections by the Energy Information Agency of the U.S. Department of Energy that in the future imported LNG could supply as much as 6% of demand. Some gas industry projections are that imported LNG could grow to supply more than 10% of demand.

[0020] Salt caverns are used to store natural gas that has been produced from wells and transported to the salt caverns via pipelines. Salt cavern storage of natural gas sourced from pipelines is well known to those skilled in the art. Generally pipelines operate at pressures lower than the maximum operating pressures of salt caverns therefore high-pressure compressors are used to boost the pressure from the pipelines and inject the natural gas in to salt caverns. Salt caverns for natural gas storage are

preferably operated in a temperature range of approximately +40°F to +140°F and pressures from about 1500 to about 4000 psig. Salt has varying degrees of plasticity depending primarily upon temperature and pressure. The hot discharge from natural gas compressors is commonly cooled prior to injection into salt caverns to temperatures below +140°F to reduce salt movement or "creep." Salt caverns store natural gas at pressures exceeding the operating pressures of the pipelines to which they are connected so the general method of delivery from the caverns to the pipelines is by the positive pressure differential from the cavern to the pipelines. In periods of high natural gas demand salt cavern storage facilities are depleted rapidly and generally the storage inventories are not replenished until periods of low natural gas demand. The practice in the industry of filling a salt cavern storage facility and then redelivering the inventory to a natural gas pipeline network is called a turnaround or turn. The number of turns a facility can perform during a period of time is a measure of its utilization. In periods of continued high demand for natural gas such as in a prolonged cold wave there may be an inability to refill the salt cavern storage facility because of the general inability of the U.S. domes-

tic production of natural gas to match the high rates of natural gas consumption. In general natural gas production from production wells is at a relatively steady rate while consumption of natural gas in the U.S. is highly variable and subject to significant peaks and valleys. Salt cavern storage facilities are recognized as an excellent way to fill the gaps in supply and demand on a quick response basis. The trend in the U.S. to build more gas fueled electrical generating facilities will exacerbate the swings in demand since a gas fueled generation plant is characterized by the ability to rapidly shift its output which could increase its fuel requirement as much as 50% in a short time period.

[0021] In the U.S. there are more than 60 salt caverns utilized for storing natural gas sourced from pipelines. To the best of the Applicant's knowledge, none of the existing salt caverns used for natural gas storage are also used for the receipt and storage of natural gas sourced from LNG.

SUMMARY OF INVENTION

[0022] The Bishop One-Step Process warms a cold fluid using a heat exchanger mounted onshore or a heat exchanger mounted offshore on a platform or subsea and stores the resulting DPNG in an uncompensated salt cavern. In an al-

ternative embodiment, a conventional LNG vaporizer system can also be used to gasify a cold fluid prior to storage in an uncompensated salt cavern or transmission through a pipeline.

[0023] The term "cold fluid" as used herein means liquid natural gas (LNG), liquid petroleum gas (LPG), liquid hydrogen, liquid helium, liquid olefins, liquid propane, liquid butane, chilled compressed natural gas and other fluids that are maintained at sub-zero temperatures so they can be transported as a liquid rather than as gases. The heat exchangers of the present invention use a warm fluid to raise the temperature of the cold fluid. This warm fluid used in the heat exchangers will hereinafter be referred to as warmant. Warmant can be fresh water or seawater. Other warmants from industrial processes may be used where it is desired to cool a liquid used in such a process.

[0024] To accomplish heat exchange in a horizontal flow configuration, such as the Bishop One-Step Process, it is important that the cold fluid be at a temperature and pressure such that it is maintained in the dense or critical phase so that no phase change takes place in the cold fluid during its warming to the desired temperature. This eliminates problems associated with two-phase flow such as stratifi-

cation, cavitation and vapor lock.

[0025] The dense or critical phase is defined as the state of a fluid when it is outside the two-phase envelope of the pressure-temperature phase diagram for the fluid (see Fig. 9). In this condition, there is no distinction between liquid and gas, and density changes on warming are gradual with no change in phase. This allows the heat exchanger of the Bishop One-Step Process to reduce or avoid stratification, cavitation and vapor lock, which are problems with two-phase gas-liquid flows.

[0026] The present invention is a Flexible Natural Gas Storage Facility. The Flexible Natural Gas Storage Facility stores natural gas in one or more man-made salt caverns typically located in a single salt dome. The Flexible Natural Gas Storage Facility can access different sources of natural gas. A first gas source is from a natural gas pipeline(s) and a second gas source is from LNG. Depending on economic conditions, supply conditions and other factors, the Flexible Natural Gas Storage Facility can receive gas from the natural gas pipeline(s) and/or from LNG to fill the salt caverns. Of course, the LNG must be warmed before being stored in a salt cavern. The preferred LNG source is from a transport ship. Pipeline gas is the only source of gas for

conventional natural gas storage in a salt cavern. Conventional natural gas salt cavern storage facilities therefore lack the flexibility and economic advantages of the present invention which is capable of receiving fluids from at least two different sources.

BRIEF DESCRIPTION OF DRAWINGS

[0027] Fig. 1 is a schematic view of the apparatus used in the Bishop One-Step Process including a dockside heat exchanger, salt caverns and a pipeline.

[0028] Fig. 2 is an enlarged section view of the heat exchanger of Fig. 1. The flow arrows indicate a parallel flow path. Surface reservoirs or ponds are used to store the warmant.

[0029] Fig. 3 is a section view of the heat exchanger of Fig. 2 except the flow arrows now indicate a counter-flow path. Surface reservoirs or ponds are used to store the warmant.

[0030] Fig. 4 is a schematic view of the apparatus used in the offshore Bishop One-Step Process including a heat exchanger mounted on the sea floor, salt caverns and a pipeline.

[0031] Fig. 5 is an enlarged section view of a portion of the equipment in Fig. 4 showing a parallel flow heat exchanger mounted on the sea floor.

[0032]　Fig. 6 is a section view of a portion of the heat exchanger along the lines 6-6 of Fig. 2.

[0033]　Fig. 7 is a section view of an alternative embodiment of the heat exchanger.

[0034]　Fig. 8 is a section view of a second alternative embodiment of the heat exchanger.

[0035]　Fig. 9 is a temperature-pressure phase diagram for natural gas.

[0036]　Fig. 10 is a schematic view of an alternative embodiment including a vaporizer system for gasification of cold fluids with subsequent storage in salt caverns without first going to a cryogenic storage tank.

[0037]　Fig. 11 is a block diagram of the Flexible Natural Gas Storage Facility including four salt caverns.

DETAILED DESCRIPTION

[0038]　Fig. 1 is the schematic view of the apparatus used in the Bishop One-Step Process including a dockside heat exchanger for converting a cold fluid to a dense phase fluid for delivery to various subsurface storage facilities and/or a pipeline (Fig. 1 is not drawn to scale.). The entire onshore facility is generally identified by the numeral 19. Seawater 20 covers much, but not all, of the surface 22 of the earth 24. Various types of strata and formations are

formed below the surface 22 of the earth 24. For example, a salt dome 26 is a common formation along the Gulf Coast both onshore 27 and offshore.

[0039] A well 32 extends from the surface 22 through the earth 24 and into the salt dome 26. An uncompensated salt cavern 34 has been washed in the salt dome 26 using techniques that are well known to those skilled in the art. Another well 36 extends from the surface 22, through the earth 24, the salt dome 26 and into a second uncompensated salt cavern 38. The upper surface 40 of the salt dome 26 is preferably located about 1500 feet below the surface 22 of the earth, although salt domes occurring at other depths both onshore 27 or offshore 28 may also be suitable. A typical cavern 34 may be disposed 2,500 feet below the surface 22 of the earth 24, have an approximate height of 2,000 feet and a diameter of approximately 200 feet. The size and capacity of the cavern 34 will vary. Salt domes and salt caverns can occur completely onshore 27, completely offshore 28 or somewhere in between. A pipeline 42 has been laid under the surface 22 of the earth 24.

[0040] A dock 44 has been constructed on the bottom 46 of a harbor, not shown. A cold fluid transport ship 48 is tied

up at the dock 44. The cold fluid transport ship 48 typically has a plurality of cryogenic tanks 50 that are used to store cold fluid 51. The cold fluid is transported in the cryogenic tanks 50 as a liquid having a sub-zero temperature. Low-pressure pump systems 52 are positioned in the cryogenic tanks 50 or on the transport ship 48 to facilitate off loading of the cold fluid 51.

[0041] After the cold fluid transport ship 48 has tied up to the dock 44, an articulated piping system 54 on the dock 44, which may include hoses and flexible loading arms, is connected to the low-pressure pump system 52 on the transport ship 48. The other end of the articulated piping system 54 is connected to high-pressure pump system 56 mounted on or near the dock 44. Various types of pumps are used in the LNG industry including vertical, multistaged deepwell turbines, multistage submersibles and multistaged horizontal.

[0042] When it is time to begin the off loading process, the low-pressure pump system 52 and the high-pressure pump system 56 transfer the cold fluid 51 from the cryogenic tanks 50 on the transport ship 48 through hoses, flexible loading arms and articulated piping 54 and additional piping 58 to the inlet 60 of a heat exchanger 62 used in

the present invention. When the cold fluid 51 leaves the high-pressure pump system 56 it has been converted to a dense phase fluid 64 because of the pressure imparted by the pump. The term dense phase is discussed in greater detail below concerning Fig. 9. The Bishop Process™ heat exchanger 62 will warm the cold fluid to approximately +40°F or higher, depending on downstream requirements. Bishop Process™ is a trademark for heat exchangers owned by Conversion Gas Imports, L.P. of Houston, Texas. This heat exchanger makes use of the dense phase state of the fluid and a high Froude number for the flow to ensure that stratification, phase change, cavitation and vapor lock do not occur in the heat exchange process, regardless of the orientation of the flow with respect to gravity. These conditions are essential to the warming operation and are discussed in detail below in connection with Fig. 9. When the cold fluid 51 leaves the outlet 63 of the heat exchanger 62, it is a dense phase fluid 64. A flexible joint 65 or an expansion joint is connected to the outlet 63 of the heat exchanger 62 to accommodate expansion and contraction of the cryogenically compatible piping 61, better seen in Fig. 2, inside the heat exchanger 62 (high nickel steel may be suitable for the piping 61).

[0043] Piping 70 connects the heat exchanger 62 with a wellhead 72, mounted on a well 36. Additional piping 74 connects the heat exchanger 62 with another wellhead 76, mounted on the well 32. The high-pressure pump system 56 generates sufficient pressure to transport the dense phase fluid 64 through the flexible joint 65, the piping, through the wellhead 72, the well 36 into the uncompensated salt cavern 38. Likewise the pressure from the high-pressure pump system 56 will be sufficient to transport the dense phase fluid 64 through the flexible joint 65, the piping 70 and 74, through the wellhead 76 and the well 32 into the uncompensated salt cavern 34. Dense phase fluid 64 therefore can be injected via the wells 32 and 36 for storage into uncompensated salt caverns 34 and 38.

[0044] In addition, dense phase fluid 64 can be transferred from the heat exchanger 62 through piping 78 to a throttling valve 80 or regulator which connects via additional sub-surface or surface piping 84 to the inlet 86 of the pipeline 42. The dense phase fluid 64 is then transported via the pipeline 42 to market. (The pipeline 42 may also be on the surface.)

[0045] If additional pumps are needed, they may be added to the piping system at appropriate points, not shown in this

schematic. The cold fluid 51 may also be delivered to the facility 19 via inland waterway, rail or truck, not shown.

[0046] Fig. 2 is an enlarged section view of the Bishop Process™ heat exchanger 62. (Fig. 2 is not drawn to scale.) The heat exchanger 62 can be formed from one section or multiple sections as shown in Fig. 2. The number of sections used in the heat exchanger 62 depends on the spatial configuration and the overall footprint of the facility 19, the temperature of the cold fluid 51, the temperature of the warrant 99 and other factors. The heat exchanger 62 includes a first section 100 and a second section 102. The term "warmant" as used herein means fresh water 19 (including river water) or seawater 20, or any other suitable fluid including that participating in a process that requires it to be cooled, i.e. a condensing process.

[0047] The first section 100 of the heat exchanger 62 includes a central cryogenically compatible pipe 61 and an outer conduit 104. (High nickel steel pipe may be suitable in this low temperature application). The interior cryogenically compatible conduit 61 is positioned at or near the center of the outer conduit 104 by a plurality of centralizers 106, 108 and 110.

[0048] A warmant 99 flows through the annular area 101 of the

first section 100 of heat exchanger 62. The annular area 101 is defined by the outside diameter of the cryogenically compatible pipe 61 and the inside diameter of the outer conduit 104.

[0049] The second section 102 of the heat exchanger 62 is likewise formed by the cryogenically compatible pipe 61 and the outer conduit 112. The cryogenically compatible pipe 61 is positioned, more or less, in the center of the outer conduit 112 by a plurality of centralizers 114, 116 and 118. All of the centralizers, 106, 108, 110, 114, 116 and 118, are formed generally the same as shown in Fig. 6.

[0050] A first surface reservoir 120, sometimes referred to as a pond, and a second surface reservoir 122 are formed onshore 27 near the heat exchanger 62 and are used to store warmant 99. Piping 124 connects the first reservoir 120 with a low-pressure pump 126. Piping 128 connects the low-pressure pump 126 with ports 130 to allow fluid communication between the reservoir 122 and the first section 100 of heat exchanger 62. The warmant flows through the annular area 101 as indicated by the flow arrows and exits the first section 100 of the heat exchanger 62 at ports 132 as indicated by the flow arrows. Additional piping 134 connects the ports 132 with the second

reservoir 122.

[0051] Piping 136 connects the first reservoir 120 with low-pressure pump 138. Piping 140 connects low-pressure 138 with ports 142 formed in the second section 102 of the heat exchanger 62. The warmant is pumped from the first reservoir 120 through the pump 138 into the annular area 103 between the outside diameter of the cryogenically compatible pipe 61 and the inside diameter of the outer conduit pipe 112. The warmant 99 flows through the annular area 103 of the second section 102 of the heat exchanger 62 as indicated by the flow arrows and exits at the ports 144 which are connected by pipe 146 to the second reservoir 122. The cold fluid 51 enters the inlet 60 of the heat exchanger 62 as a cold liquid and leaves the outlet 63 as a warm dense phase fluid 64. The cryogenically compatible pipe 61 is connected to a flexible joint 65 to account for expansion and contraction of the cryogenically compatible pipe 61. All piping downstream of flexible joint 65 is not cryogenically compatible.

[0052] In the parallel flow configuration of Fig. 2, the heat exchanger 62 transfers warmant 99 from the first surface reservoir 120 through the first section 100 to the second reservoir 122. Likewise, additional warmant is transferred

from the first reservoir 120 through the second section 102 of the heat exchanger 62 to the second reservoir 122. Over time, the volume of warmant 99 and the first reservoir 120 will be diminished and the volume of warmant 99 in the second reservoir 122 will be increased. It will therefore be necessary to move to a counter-flow arrangement better seen in Fig. 3 so that the warmant 99 can be transferred from the second reservoir 122 back to the first reservoir 120. In an alternative arrangement, that avoids the necessity for counter-flow, the warmant 99 can be returned from the first section 100 through piping 148, shown in phantom, to the first reservoir 120 allowing for continuous parallel flow through the first section 100 of the heat exchanger 62. In a similar arrangement, the warmant from the second section 102 is transferred from a second reservoir 122 through piping 150, shown in phantom, to the pump 138. In this fashion, the warmant 99 is continually cycled in a parallel flow through the second section 102 of the heat exchanger 62. If river water is used as the warmant 99, the surface ponds 120 and 122 are not needed. Instead, the piping 124 connects to a river, as does the piping 136, 134 and 146. When river water is used as a warmant 99 it is always returned to its

source and the piping is modified accordingly.

[0053] It is important to avoid freez-up of the heat exchanger 62. Freez-up blocks the flow of warmant 94 and renders the heat exchanger 62 inoperable. It is also important to reduce or eliminate icing. Icing renders the heat exchanger 62 less efficient. It is therefore necessary to carefully design the area, generally identified by the numeral 63 where the cold fluid 51 in the pipe 61 first encounters the warmant 99 in the annular area 101 of the first section 100 of the heat exchanger 62. Here it is necessary to prevent or reduce freezing of the warmant 99 on the pipe 61, which could block the ports, 130 and the annular area 101. In most cases, it is possible to choose flow rates and pipe diameter ratio such that freezing is not a problem. For example, if a dense phase natural gas expands by a factor of four in the warming process, the heat balance then indicates that the warmant flow rate is required to be four times that of the inlet dense phase. This results in a diameter ratio of two (outer pipe/inner pipe) in order to balance friction losses in the two paths. However, the heat transfer rate is improved if the diameters are closer together. An optimum ratio is approximately 1.5. Where conditions are extreme, it is possible to prevent local

freezing by increasing the thermal insulation at the wall of the cryogenically compatible pipe 61 in this region 63. One method for doing this is to simply increase the wall thickness of the pipe 61. This has the effect of pushing some of the warming function downstream to where the cold fluid 51 has already been warmed to some extent, and the possibility of freezing has been reduced. This may also increase the length of the heat exchanger.

[0054] Fig. 3 is an enlarged section view of the Bishop Process™ heat exchanger 62 in a counter-flow mode. (Fig. 3 is not drawn to scale.) Warmant 99 is transferred from the second reservoir 122 through piping 200, the pump 202, piping 204, the ports 144 into the annular area 103 of the second section 102 of the heat exchanger 62 as indicated by the flow arrows. The warmant 99 exits the annular area 103 through the ports 142 and travels through the piping 206 to the first reservoir 120. Low-pressure pump 138 transfers warmant 99 from the second reservoir 122 through piping 150, 206 and the ports 132 into the annular area 101 of the first section 100 of the heat exchanger 62 as indicated by the flow arrows. The warmant 99 leaves the annular area 102 of the first section 100 through the ports 130 and piping 210 to return to the first reservoir

120. This counter-flow circuit continues until most of the warmant 99 has been transferred from the second reservoir 122 back to the first reservoir 120.

[0055] In an alternative flow arrangement, the warmant 99 leaves the annular area 103 through the ports 142 and is transferred through the piping 212, shown in phantom, back to the second reservoir 122 making a continuous loop from and to the second reservoir 122. Likewise warmant 99 can be transferred from the first reservoir 120 through piping 214, as shown in phantom, to the pump 138, piping 206 through the ports 132 into the annular area 101 of the first section 100 of the heat exchanger 62. The warmant is then returned through the ports 130 and the piping 210 to the first reservoir 120.

[0056] The design of the heat exchanger 62 and the number of surface reservoirs is determined by a number of factors including the amount of space that is available and ambient temperatures of warmant 99. For example, if the warmant 99 has an average temperature of more than 80°F, the heat exchanger 62 may only need one section. However, if the warmant 99 is on average less than 80°F, two or more segments may be necessary, such as the two-segment design shown in Figs. 2 and 3. Surface reservoirs

that are relatively shallow and have a large surface area are desirable for this purpose because they act as a solar collector raising the temperature of the warmant 99 during sunny days. This alternative arrangement constitutes a continuous counter-flow loop from and to the first reservoir 120. In the alternative, if the river water is being used as the warmant, no reservoirs may be required. In the case of river water, it may simply be returned to the river.

[0057]   EXAMPLE # 1

[0058]   This hypothetical example is designed to give broad operational parameters for the Bishop One-Step Process conducted at or near dockside as shown in Fig. 1. A number of factors must be considered when designing the facility 19 including the type of cold fluid and warmant that will be used. Conventional instrumentation for process measurement, control and safety are included in the facility as needed including but not limited to: temperature and pressure sensors, flow measurement sensors, overpressure reliefs, regulators and valves. Various input parameters must also be considered including, pipe geometry and length, flow rates, temperatures and specific heat for both the cold fluid and the warmant. Various output parameters must also be considered including the type, size,

temperature and pressure of the uncompensated salt cavern. For delivery directly to a pipeline, other output parameters must also be considered such as pipe geometry, pressure, length, flow rate and temperature. Other design parameters to prevent freez-up include temperature of the warmant at the inlet and the outlet of each section of the heat exchanger, temperature in the reservoirs, and the temperature at the initial contact area 63. Other important design considerations include the size of the cold fluid transport ship and the time interval during which the ship must be fully offloaded and sent back to sea.

[0059] Assume that 800,000 barrels of LNG (125,000 cubic meters) are stored in the cryogenic tanks 50 on the transport ship 48 at approximately one atmosphere and a temperature of –250° F or colder. The low-pressure pump system 52 has the following general operational parameters: approx. 22,000 gpm (5000m3/hr) with approx. 600 horsepower to produce a pressure of approximately 60 psig (4 bars). Due to frictional losses approximately 40 psig is delivered to the intake of the high-pressure pump system 56. The high-pressure pump system 56 will raise the pressure of the LNG typically to 1860 psig (120 bars) or more so that the cold fluid 51 will be in the dense phase

after it leaves the high-pressure pump system 56. There are approximately ten pumps in the high-pressure pump system 56, each with a nominal pumping rate of 2,200 gpm (500m3/hr) at a pressure increase of 1860 psig (120 bars), resulting in approximately 1900 psig (123 bars) available for injection into the uncompensated salt caverns 34 and 38. The total required horsepower for the ten high-pressure pump system is approximately 24,000 hp. This represents the maximum power required when the uncompensated salt caverns are fully pressured, i.e. when they are full. The average fill rate may be higher than 22,000 gpm (5000m3/hr). Assuming 13 3/8" nominal diameter pipe in the injection wells 32 and 36, approximately four uncompensated salt caverns having a minimum total capacity of approximately 3 billion cubic feet. The volume of the LNG will generally expand by a factor 2-4 during the heat exchange process, depending on the final pressure in the uncompensated salt cavern. Larger injection wells are feasible, along with more caverns if higher flows are needed.

[0060] Pumps 124 and 138 for the warmant 99 will be high-volume, low-pressure pump system with a combined flow rate of about 44,000 gpm (10,000m3/hr) at about 60 psig

(4 bars). The flow rate of the warmant through the heat exchanger 62 will be approximately two to four times the flow rate of the LNG through the cryogenically compatible tubing 61. The flow rate of the warmant will depend on the temperature of the warmant and the number of sections in the heat exchanger. (Each section has a separate warmant injection point.) The warmant could be treated for corrosion and fouling prevention to improve the efficiency of the heat exchanger 62. As the dense phase fluid 64 passes through the heat exchanger 62 it warms and expands. As it expands, the velocity increases through the heat exchanger.

[0061] Assuming an LNG flow rate of 22,000 gpm the heat exchanger 62 could have a cryogenically compatible center pipe 61 with a nominal outside diameter of approximately 13 3/8 inches and the outer conduits 104 and 112 could have a nominal outside diameter of approximately 20 inches. The overall length of the heat exchanger 62 would be long enough, given the temperature of the warmant and other factors to allow the dense phase fluid 64 to reach a temperature of about 40°F. This could result in an overall length of several thousand feet and perhaps in the neighborhood of 5,000 feet. Multiple warmant injection

points and parallel flow lines can greatly reduce this length. Depending on the distance from the receiving point to the storage space, the length may not be a problem. Parallel systems may also be used depending on the size of the facility and the need for redundancy. Pipe size and length can be greatly reduced by dividing the LNG flow into separate parallel paths. Two parallel heat exchangers 62 could have a cryogenically compatible center pipe 61 with a nominal outside diameter of approximately 8 inches and the outer conduits 104 and 112 could have a nominal outside diameter of approximately 12 inches. Use of parallel heat exchangers 62 is a design choice dependent upon material availability, ease of construction, and distance to storage.

[0062] In addition, the heat exchanger 62 need not be straight. To conserve space, or for other reasons the heat exchanger 62 may adopt any path such as an S-shaped design or a corkscrew-shaped design. The heat exchanger 62 can have 90°elbows and 180° turns to accommodate various design requirements.

[0063] If the dense phase fluid 64 is to be stored in an uncompensated salt cavern 34, one first needs to determine the minimum operational pressure of the salt cavern 34. For

example, hypothetically, if the uncompensated cavern 34 had a maximum operating pressure of about 2,500 psig, the high-pressure pump system 56 would have the ability to pump at 2,800 psig or more. Of course operating at less than maximum is also possible, provided that pressure exceeds about 1,200 psig to maintain dense phase.

[0064] If the cold fluid 51 is to be heated and transferred directly into the pipeline 42, one first needs to determine the operational pressure of the pipeline. For example, hypothetically, if the pipeline operates at 1,000 psig, the high-pressure pump system 56 might still need to operate at pressures above 1,200 psig to maintain the dense phase of the fluid 64 depending on the temperature-pressure phase diagram. In order to reduce the pressure of the dense phase fluid 64 to pipeline operating pressures, it passes through the throttling valve 80 or regulator prior to entering the pipeline 42. Heating might also be necessary at this point to prevent the formation of two-phase flow, i.e. to keep liquids from forming. Conversely, the heat exchanger could be lengthened to increase the temperature such that subsequent expansion and cooling does not take the fluid out of the dense phase.

[0065] After dense phase fluid 64 has been injected into the un-

compensated caverns 34 and 38, it can be stored until needed. The dense phase fluid 64 may be stored in the uncompensated salt cavern at pressures well exceeding the operational pressures of the pipeline. Therefore, all that is needed to transfer the dense phase fluid from the salt cavern 34 and 38 is to open valves, not shown, on the wellheads 72 and 76 and allow the dense phase fluid to pass through the throttling valve 80 or regulator which reduces its operational pressure to pressures compatible with the pipeline. In conclusion, the well 32 acts both to fill and empty the uncompensated salt cavern 34 as indicated by the flow arrows. Likewise, well 36 acts to both fill and empty the salt cavern 38 as indicated by the flow arrows.

[0066] Fig. 4 is a schematic view of the apparatus used in the Bishop One-Step Process when a ship is moored offshore 28. (Fig. 4 is not drawn to scale.) The facility 298 is located offshore 28 and the facility 299 is located onshore 27. The offshore facility 298 may be several miles from land and is connected to the onshore facility 299 by a subsea pipeline 242.

[0067] A subsea Bishop Process™ heat exchanger 220 may be located on the sea floor 222 in proximity to the platform

226. In an alternative embodiment, not shown, the heat exchanger 220 could be mounted on the platform 226 above the surface 21 of the water 20. In a second alternative embodiment, not shown, the heat exchanger 220 could be mounted on and between the legs 227 (Best seen in Fig. 5) of the platform 226. When mounted on or between the legs 227, all or part of the heat exchanger 220 could be below the surface 21 of the water 20. The mooring/docking device 224 is secured to the sea floor 222 and allows cold fluid transport ships 48 to be tied up offshore 28. Likewise a platform 226 has legs 227, which are secured to the sea floor 222, and provides a stable facility for equipment and operations described below.

[0068] After the cold fluid transport ship 48 has been successfully secured to the mooring/docking device 228, articulated piping, hoses and flexible loading arms 228 are connected to the low-pressure pump system 52 located in the cryogenic tanks 50 or on board the transport ship 48. The other end of the articulated piping 228 is connected to a high-pressure pump system 230 located on the platform 226. Additional cryogenically compatible piping 232 connects the high-pressure pump system 230 to the inlet 234 of the subsea heat exchanger 220.

[0069] After the cold fluid 51 passes through the high-pressure pump system 230 it is converted into a dense phase fluid 64 and then passes through the heat exchanger 220. The fluid 64 stays in the dense phase as it passes through the heat exchanger 220. The outlet 236 of the heat exchanger 220 is connected to a flexible joint 238 or an expansion joint. The cryogenically compatible piping 235 in the heat exchanger 220 connects to one end of the flexible joint 238 and non-cryogenically piping 240 connects to the other end of the flexible joint 238. This allows for expansion and contraction of the cryogenically compatible piping 235. The subsea pipeline 242 is formed from non-cryogenically compatible piping.

[0070] The subsea pipeline 242 connects to a wellhead 76, which connects to the well 32 and the uncompensated salt cavern 34. Again, by opening valves, not shown, on the wellhead 76, dense phase fluid 64 can be transported from the subsea pipeline 242 through the well 32 and injected in the uncompensated salt cavern 34 for storage.

[0071] In addition, the dense phase fluid 64 can be transported through the subsea pipeline 242 to a throttling valve 80 or regulator which reduces the pressure and allows the dense phase fluid 64 to pass through the piping 84 into

the inlet 86 of the pipeline 42 for transport to market.

[0072] After a sufficient amount of dense phase fluid 64 has been stored in the salt cavern 34, the valves, not shown, on the wellhead 76 can be shut off. This isolates the dense phase fluid 64 under pressure in the uncompensated salt cavern 34. In order to transfer the dense phase fluid 64 from the uncompensated salt cavern 34 to the pipeline 42, other valves, not shown, are opened on the wellhead 76 allowing the dense phase fluid which is under pressure in the uncompensated salt cavern 34 to move through the throttling valve 80 or regulator and the pipe 84 to the pipeline 42.

[0073] Because the pressure in the uncompensated salt cavern 34 is higher than the pressure in the pipeline 42, all that is necessary to get the dense phase fluid to market is to open one or more valves, not shown, on the wellhead 76 which allows the dense phase fluid 64 to pass through the throttling valve 80. The well 32 is used to inject and re-move dense phase fluid 64 from the uncompensated salt cavern 34 as shown by the flow arrows.

[0074] Fig. 5 is an enlargement of the offshore facility 298 and subsea Bishop Process™ heat exchanger 220 of Fig. 4. (Fig. 5 is not drawn to scale.) The subsea heat exchanger

220 includes a first section 250 and a second section 252. The cryogenically compatible piping 235 is positioned in the middle of the outer conduits 254 and 256 by a plurality of centralizers 258, 260, 262 and 264. These centralizers used in the subsea heat exchanger 220 are identical to the centralizers used in the surface mounted heat exchanger 62 as better-seen in Fig. 6. Some slippage must be allowed between the centralizers and the outer conduits 254 and 256 to allow for expansion and contraction.

[0075] Cold fluids 51 leave the cryogenic storage tanks 50 on the cold fluid transport ship 48 and are pumped by the low-pressure pump 52 through the articulated piping 228 to the high-pressure pump system 230 located on the platform 226. The cold fluid 51 then passes through piping 232 to the inlet 234 of the subsea heat exchanger 220. The piping 228, 232 and 235 must be cryogenically compatible with the cold fluid 51.

[0076] The offshore heat exchanger 220 uses seawater 20 as a warmant 99. The warmant enters piping 246 on the platform 226 and passes through the low-pressure warmant pump 244. The warmant pump 244 may also be submersible. Piping 248 connects the low-pressure warmant pump 244 to the inlet ports 266 on the first section 250

of the heat exchanger 220. The warmant 99 passes through the annular area 268 between the outside diameter of the cryogenically compatible pipe 235 and the inside diameter of the pipe 254. The warmant 99 then exits the outlet ports 270 as indicated by the flow arrows. A submersible low-pressure pump 272 pumps additional warmant 99 into the second section 252 of the heat exchanger 220. In the alternative, the pump 272 could also be located on the platform 226. The warmant passes through the inlet ports 274 into the annular area 276 as indicated by the flow arrows. The annular area 276 is between the outside diameter of the cryogenically compatible pipe 235 and the interior diameter of the outer conduit 256. The warmant 99 exits the second section 252 through the outlet ports 278 as indicated by the flow arrows.

[0077] The cold fluid 51 enters the heat exchanger at the inlet 234 as a dense phase fluid 64 as it leaves the outlet 236 of the heat exchanger 220 as a dense phase fluid. The cryogenically compatible pipe 235 is connected to non-cryogenically compatible pipe 240 by a flexible joint 238 or an expansion joint. This allows the remainder of the subsea pipeline 242 to be constructed from typical carbon

steels that are less expensive than cryogenically compatible steels. The heat exchanger 220 must be designed to avoid freez-up and to reduce or avoid icing within the heat exchanger 62. Similar design considerations, previously discussed that apply to the heat exchanger 62 also apply to the heat exchanger 220.

[0078] EXAMPLE # 2

[0079] This hypothetical example is designed to give broad operational parameters for the Bishop One-Step Process conducted offshore as shown in Figs. 4 and 5. A number of factors must be considered when designing the facilities 298 and 299 including the type of cold fluid and the temperature of the warmant that will be used. Conventional instrumentation for process measurement, control and safety are included in the facility as needed including but not limited to: temperature and pressure sensors, flow measurement sensors, overpressure reliefs, regulators and valves. Various input parameters must also be considered including, pipe geometry and length, flow rates, temperatures and specific heat for both the cold fluid and the warmant. Various output parameters must also be considered including the type, size, temperature and pressure of the uncompensated salt cavern. For delivery

directly to a pipeline, other output parameters must also be considered such as pipe geometry, pressure, length, flow rate and temperature. Other design parameters to prevent freez-up include temperature of the warmant at the inlet and the outlet of each section of the heat exchanger, and the temperature at the initial contact area 235. Other important design considerations include the size of the cold fluid transport ship and the time interval during which the ship must be fully offloaded and sent back to sea.

[0080] Assume that 800,000 barrels of LNG (125,000 cubic meters) are stored in the cryogenic tanks 50 on the transport ship 48 at approximately one atmosphere and a temperature of 250°F or colder. The cold fluid transport ship 48 is moored to a dolphin 224 or some other suitable mooring/docking apparatus such as a single point mooring/docking or multiple anchored mooring/docking lines. LNG flows from the ship 48 through the low-pressure pump system 52, through hoses, flexible loading arms and/or articulated piping 228 to the high-pressure pump system 230 on the platform 226. The dense phase fluid 64 leaves the outlet of the high-pressure pump system 230 and enters the heat exchanger 220. The heat exchanger 220 is

shown on the sea floor 222, but it could be located elsewhere as previously discussed. Also the heat exchanger 222 can assume various shapes as previously discussed in Example 1.

[0081] Ambient heated vaporizers are known in conventional LNG facilities (See pg. 69 of the Operating Section Report of the AGA LNG Information Book, 1981). According to the aforementioned Operating Section Report, "Most base load (ambient heated) vaporizers use sea or river water as the heat source." These are sometimes called open rack vaporizers. On information and belief, conventional open rack vaporizers generally operate at pressures in the neighborhood of 1,000–1,200 psig. These open rack vaporizers are different than the heat exchangers 62 and 220 used in the Bishop One-Step Process.

[0082] Comparison of heat exchangers used in the invention with conventional open rack vaporizers.

[0083] First, the heat exchangers in the Bishop One-Step Process easily accommodate higher pressures suitable for injection into uncompensated salt caverns. Typically, conventional vaporizer systems are not designed for operational pressures in excess of 1,200 psig.

[0084] Second, the sendout capacity of each conventional open

rack vaporizer is substantially less than the sendout capacity of the heat exchangers used in the Bishop One-Step Process. On information and belief, several open rack vaporizers must be used in a bank to achieve the desired sendout capacity that can be achieved by one Bishop One-Step Process heat exchanger.

[0085] Third, the conventional open rack vaporizer is also believed to be more prone to ice formation and freezing problems that the heat exchangers in the Bishop One-Step Process. Vaporizers that avoid this problem sometimes use water-glycol mixtures, which introduce an environmental hazard.

[0086] Fourth, the heat exchanger used in the Bishop One-Step Process provides a needed path to the uncompensated salt cavern or pipeline, in addition to heating the fluid. The length of the exchanger can be varied by using alternate designs as needed.

[0087] Fifth, the heat exchanger used in the Bishop One-Step Process is easily flushed for cleaning, as with a biocide. There is little chance of clogging when doing this.

[0088] Sixth, the construction of the heat exchanger used in the Bishop One-Step Process is extremely simple from widely available materials, and can be done on site.

[0089]   Seventh, the heat exchanger used in the Bishop One-Step Process can accommodate a wide range of cold fluids with no change in design LNG, ethylene, propane, etc.

[0090]   Eighth, the heat exchanger used offshore in the Bishop One-Step Process uses little space, (because it can be on the sea floor) which is highly advantageous on platforms. The weight contribution is also almost negligible.

[0091]   Ninth and dependent on all of the above features, the heat exchanger used in the Bishop One-Step Process is extremely low cost both in capital and operations.

[0092]   Recognizing some of these performance problems with open rack vaporizers, Osake Gas has developed a new vaporizer called the SUPERORV, which uses seawater as the warmant. Drawings of the SUPERORV and conventional open rack vaporizers are shown on the Osaka Gas web site (www.osakagas.co.jp). The distinctions listed above between the heat exchanger used in the Bishop One-Step Process are likewise believed to be applicable to the SUPERORV.

[0093]   Fig. 6 is a section view of the first section of the heat exchanger along the line 6-6 of Fig. 2. (Fig. 6 is not drawn to scale.) The coaxial heat exchanger 62 includes a center pipe 61 formed of material suitable for low temperature

and high-pressure service, while the outer conduit 104 may be a material not suited for this service. This allows the outer conduit 104 to be formed from plastic, fiberglass or some other material that may be highly corrosion or fouling resistant, as it needs to be in order to transport the warmant 99 such as fresh water 19 or sea water 20. The annular area 101 between the outside diameter of the central pipe 61 and the inside diameter of the outer conduit 104 may need to be treated chemically periodically for fouling. The center pipe 61 will typically have corrosion resistant properties.

[0094] The center pipe 61 will be equipped with conventional centralizers 108 to keep it centered in the outer conduit 104. This serves two functions. Centralizing allows the warming to be uniform and thus minimize the occurrence of cold spots and stresses. Perhaps more importantly, the supported, centralized position allows the inner pipe 61 to expand and contract with large changes in temperature. The centralizer 108 has a hub 107 that surrounds the pipe 61 and a plurality of legs 109 that contact the inside surface of the outer conduit 104. The legs 109 are not permanently attached to the outer conduit 104 and permit independent movement of the inner pipe 61 and

the outer conduit 104. This freedom of movement is important in the operation of the invention. To further permit expansion and contraction in the surface mounted heat exchanger 62 of Fig. 1, the outlet 63 is connected to a flexible joint 65 which also connects to non-cryogenically compatible piping 70. Likewise in subsea heat exchanger 220 of Figs. 4 and 5, the outlet 236 is connected to a flexible joint 238 which also connects to non-cryogenically compatible piping 240. All of the centralizers that are used in this invention should allow movement (expansion, contraction and elongation) of the cryogenically compatible inner pipe independent of the outer conduit without causing significant abrasion and unnecessary wear on either. The cold fluid 51 passing through the cryogenically compatible piping is crosshatched in Figures 6, 7 and 8 for clarity.

[0095] Fig. 7 is a section view of an alternative embodiment of the heat exchanger used in the Bishop One-Step Process. In the alternative embodiment of Fig. 7, a central cryogenically compatible pipe 300 is centered inside of an intermediate cryogenically compatible pipe 302 by centralizers 304. The intermediate pipe 302 is centered inside the outer conduit 104 by centralizers 305. The centralizer

305 has a centralizer hub 302, which is held in place by a plurality of legs 306. An annular area 308 is defined between the outside diameter of the intermediate pipe 302 and the inside diameter of the outer conduit 104. Warmant 99 passes through the annular area 308. The legs 306 are not permanently attached to the inside of the outer conduit 104 to allow the cryogenically compatible pipes to expand and contract independent of the outer conduit 104. Warmant 99 also passes through the central pipe 300. The cold fluid 51 passes through the annular area 309 between the outside diameter of the central pipe 300 and the inside diameter of the centralizer hub 302. The cold fluid 51 in the annular area 309 is crosshatched in Fig. 7 for clarity. The alternative design of Fig. 7 has a greater heat exchange area and therefore the length of a heat exchanger using the alternative design of Fig. 7 may be shorter than the design in Fig. 6. In those circumstances where a relatively short heat exchanger may be preferable, the alternative design of Fig. 7 may be more suitable than the design of Fig. 6. In some circumstances, it may be necessary to develop even a shorter heat exchanger.

[0096] Fig. 8 is a section view of a second alternative embodi-

ment of the heat exchanger used in the Bishop One-Step Process. Interior cryogenically compatible pipes 320, 322, 324 and 326 are held in a bundle and are centered inside the outer conduit 104 by a plurality of centralizers 327. The centralizers 327 have centralizer hubs 328. The interior pipes 320, 322, 324 and 326 are crosshatched to indicate that they carry the cold fluid 51. The centralizer hub 328 is positioned in the middle of the outer conduit 104 by legs 330, which are not permanently attached to the outer conduit 104. Warmant 99 passes through the annular area 334. The alternative embodiment of Fig. 8 should allow for even a shorter length heat exchanger than the design show in Fig. 7. When space is at a premium, alternative designs such as Fig. 7 and Fig. 8 may be suitable and other designs may also be utilized that increase the area of heat interface.

[0097] Fig. 9 is a temperature-pressure phase diagram for natural gas. Natural gas is a mixture of low molecular weight hydrocarbons. Its composition is approximately 85% methane, 10% ethane, and the balance being made up primarily of propane, butane and nitrogen. In flow situations where conditions are such that gas and liquid phases may coexist, pump, piping and heat transfer problems, dis-

cussed below, may be severe. This is especially true where the flow departs from the vertical. In downward vertical flow such as shown in U.S. Patent No. 5,511,905, the liquid velocity must only exceed the rise velocity of any created gas phase in order to maintain uninterrupted flow. In cases approaching horizontal flow with a two-phase fluid, the gas can stratify, preventing the heat exchange, and in extreme cases causing vapor lock. Cavitation can also be a problem.

[0098] In the present invention, these problems are avoided by insuring that the cold fluid 51 is converted by the high-pressure pump system 56 or 230 into a dense phase fluid 64 and that it is maintained in the dense phase while a) it passes through the heat exchanger 62 or 220 and b) when it is stored in an uncompensated salt cavern. The dense phase exists when the temperature and pressure are high enough such that separate phases cannot exist. In a pure substance, for which this invention also applies, this is known at the critical point. In a mixture, such as natural gas, the dense phase exists over a wide range of conditions. In Fig. 9, the dense phase will exist as long as the fluid conditions of temperature and pressure lie outside the two-phase envelope (crosshatched in the draw-

ing). This invention makes use of the dense phase characteristic so there is no change in phase with increase in temperature or pressure when starting from a point on the phase diagram above the cricondenbar 350 or to the right of the cricondentherm 352. This allows a gradual increase in temperature with a corresponding gradual decrease in density as the fluid is warmed and expanded in the heat exchanger 62 or 220. The result is a flow process where density stratification effects become insignificant. Operational pressures for the cold fluid 51 should therefore place the fluid 64 in the dense phase in the heat exchangers 62 or 220 and downstream piping and storage. In the case of some natural gas compositions, dense phase maintenance will require pressures different from the approximately 1,200 psig shown in the example in Figure 9.

[0099] The effect of confining the fluid to the dense phase is illustrated by an analysis of the densimetric Froude Number F that defines flow regimes for layered or stratified flows:

$$F = V\left(gD\frac{\Delta\gamma}{\gamma}\right)^{-\left(\frac{1}{2}\right)}$$

[0100] Here V is fluid velocity, g is acceleration due to gravity, D is the pipe diameter and γ is the fluid density and $\Delta\gamma$ is the change in fluid density. If F is large, the terms involving stratification in the governing equation of fluid motion

dropout of the equation. As a practical example, two-phase flows in enclosed systems generally lose all stratification when the Froude Number rises to a range of from 1 to 2. In the present invention, the value of the Froude Number ranges in the hundreds, which assures complete mixing of any density variations. These high values are assured by the fact that in dense phase flow, the term $\Delta\gamma/\gamma$ in the equation above is small.

[0101] Measurement of the Froude Number occurs downstream of the high-pressure pump systems 56 and 230 and in the heat exchangers 62 and 220. In other words, the Froude Number, using the Bishop One-Step Process should be high enough to prevent stratification in the piping downstream of the high-pressure pump systems 56 and 230 and in the heat exchangers 62 and 220. Typically Froude Numbers exceeding 10 will prevent stratification. Note that conventional heat exchangers do not usually operate at pressures and temperatures high enough to produce a dense phase, and phase change problems may be avoided by other means.

[0102] In summary, using the present invention, the cold fluid 51 is kept in the dense phase by pressure as it leaves the high-pressure pump system 56 or 230 and thereafter as it

passes through the heat exchangers 62 or 220 and while it is stored in uncompensated salt cavern.

[0103] Fig. 10 is a schematic diagram of an alternative embodiment of the present invention. The onshore facility 310 uses a conventional vaporizer system 260 to warm the cold fluid 51 prior to storage or transport.

[0104] Conventional LNG facilities offload LNG and store it onshore in cryogenic storage tanks as a liquid. In a conventional facility, the LNG is then run through a conventional vaporizer system to warm the liquid and convert it into a gas. The gas is odorized and transferred to a pipeline that transmits the gas to market. A simplified flow diagram of a conventional LNG vaporizer system is shown in Figure 4.1 of the Operating Section Report of the AGA LNG Information Book, 1981, which is incorporated herein by reference. As discussed on page 64 of this document, various types of vaporizers are known including heated vaporizers, integral heated vaporizers, and remoted heated vaporizers, ambient vaporizers and process vaporizers. Any of these known vaporizers could be used in the vaporizer system 260 of Fig. 10, provided they have the capacity to quickly offload the ship 48, and providing that they can withstand the pressures necessary for downstream injec-

tion into an uncompensated salt cavern.

[0105] In the alternative embodiment shown in Fig. 10, cold fluid 51 is offloaded from the transport ship 48 by the low-pressure pump system 52 located in the cryogenic storage tanks 50 or on the vessel 48. The cold fluid 51 passes through articulated piping 54 to another high-pressure pump system 56 located on or near the dock 44. The fluid 59 then passes through additional piping 58 to the inlet 262 of the conventional vaporizer 260. The fluid 59 passes from the inlet 261 through the vaporizer 260 to the outlet 264. Unlike Examples 1 and 2, it is not necessary in this alternative embodiment to have the fluid in the dense phase while it goes through the vaporizer nor are high Froude numbers required. Though not required, use of the dense phase is also acceptable. Therefore the fluid in this alternative embodiment has been assigned a different numeral, i.e. 59. The fluid 59 passes through the non-cryogenic piping 70 and the wellhead 72 through the well 36 to the uncompensated salt cavern 38. Likewise, the fluid 59 can pass through the non-cryogenic piping 74, the wellhead 76, the well 32, to the uncompensated salt cavern 34. When the uncompensated salt caverns 34 and 38 are full, valves, not shown, on the wellheads 76

and 72 can be shut off to store the gas in the uncompensated salt caverns 34 and 38.

[0106] Typically, the fluid 59 will be stored at a pressure exceeding pipeline pressures. Therefore, all that is necessary to transfer the fluid 59 from the uncompensated salt caverns 34 and 38 is to open valves, not shown, on the wellhead 76 and 72 allowing the gas 320 to pass through the piping 78 and the throttling valve 80 or a regulator, the piping 84 to the inlet 86 of the pipeline 42. Some additional heating may be necessary to the gas prior to entering the pipeline. Therefore, the wells 32 and 36 are used for injecting fluid 59 into the uncompensated salt caverns 34 and 38 and the wells are also used as an outlet for the stored fluid 59 when it is transferred to the pipeline 42. The flow arrows in the drawing therefore go in both directions indicating the dual features of the wells 32 and 36.

[0107] EXAMPLE # 3

[0108] This hypothetical example is merely designed to give broad operational parameters for an alternative embodiment including a vaporizer system for warming of cold fluids with subsequent storage in uncompensated salt caverns and/or transportation through a pipeline, as shown in Fig. 10. Unlike conventional LNG facilities, no

cryogenic tanks are used in the on-shore facility 310 of Fig. 10. (The ship 48, as previously mentioned, does contain cryogenic tanks 50.) A conventionally designed vaporizer system 260 is used in this alternative embodiment instead of the coaxial heat exchangers 62 and 220, discussed in the previous examples. (Conventional vaporizer systems typically operate in the range of 1,000-1,200 psig.) The conventionally designed vaporizer system 260 will need to be modified to accept the higher pressures associated with uncompensated salt caverns (typically in the range of 1,500-2,500 psig). A number of factors must be considered when designing the facility 310 including the type of cold fluid and warmant that will be used. Conventional instrumentation for process measurement, control and safety are included in the facility as needed including but not limited to: temperature and pressure sensors, flow measurement sensors, overpressure reliefs, regulators and valves. Various input parameters must also be considered including, pipe geometry and length, flow rates, temperatures and specific heat for both the cold fluid and the warmant. Various output parameters must also be considered including the type, size, temperature and pressure of the uncompensated salt caverns. For de-

livery directly to a pipeline, other output parameters must also be considered such as pipe geometry, pressure, length, flow rate and temperature. Other important design considerations include the size of the cold fluid transport ship and the time interval during which the ship must be fully offloaded and sent back to sea.

[0109] A plurality of vaporizer systems 260 might be required to reach desired flow rates. The vaporizer systems used in this alternative embodiment must be designed to withstand operational pressures in the range of 1,500 to 2,500 psig to withstand the higher pressures necessary for subsurface injection.

[0110] Conventional vaporizer systems are designed to function with stratification. Unlike Examples 1 and 2, it is not necessary in this alternative embodiment to have the fluid in the dense phase while it goes through the vaporizer nor are high Froude numbers required. Though not required, use of the dense phase is also acceptable.

[0111] Referring to Fig. 10, LNG is pumped from the ship 48 using the low-pressure pump system 52, through the hoses or flexible loading arms 54 to the high-pressure pump system 56. The fluid 59 passes through the vaporizer system 260 where it is warmed. The fluid 59 then is injected

into uncompensated salt caverns. Because the offload rate from the ship 48 and the storage pressures are similar, pump and flow rate characteristics described in Example 1 are applicable to Example 3. To Applicants knowledge, there is presently no conventional LNG facility using conventional vaporizers that subsequently injects gas into an uncompensated salt cavern

[0112] Fig. 11 is a block diagram of the Flexible Natural Gas Storage Facility with four salt caverns. The drawing is not to scale. The Flexible Natural Gas Storage Facility can have a single large cavern or several separate caverns. The four caverns in Fig. 11 are merely for illustrative purposes.

[0113] The Flexible Natural Gas Storage Facility is generally identified by the numeral 400. The Flexible Natural Gas Storage Facility 400 can receive fluid from a pipeline(s) natural gas source 412 and/or a LNG source 414. This gives the Facility 400 flexibility and economic advantages over conventional natural gas salt cavern storage facilities that receive gas solely from pipelines. The LNG source can be a cold fluid transport ship 48, not shown and/or a conventional LNG receiving terminal with surface mounted tanks. As previously discussed, the surface mounted tanks are not preferred, but as an add-on to an existing terminal

may be advantageous.

[0114] The pipeline natural gas source 412 may be one or several pipelines that deliver natural gas 402, sometimes referred to as a first fluid. The pipeline natural gas source 412 is connected via piping 416 to a conventional natural gas compressor 418. The natural gas 402 flows from the pipeline natural gas source 412 to the compressor 418 where the natural gas is compressed to salt cavern pressure. The compression process also raises the temperature of the natural gas to about 200°F. The compressor 418 is connected via piping 420 to a conventional heat exchanger 422. The natural gas 402 flows from the compressor to the heat exchanger 422 where it is cooled to temperatures compatible with the salt cavern as previously explained. It is preferable, though not required, to raise the pressure of the gas from the pipeline source to dense phase levels for storage in a salt cavern. However, on some days during high drawdown, the cavern pressure may fall below dense phase levels.

[0115] The cooled, compressed natural gas 402 flows via piping 424 to the inlet 426 of the manifold 428. The manifold is connected to additional piping 430, 432 and 434 to allow distribution of natural gas to various components in the

Facility 400. The piping 434 connects the inlet and the manifold to pipeline 436. The piping 430 connects the inlet and the manifold to the pipeline 438. A second manifold 440 connects to the first pipeline 436, the second pipeline 438 and the piping 430, 432 and 434. A well 442 connects first salt cavern 444 with the Facility 400. Fluid may flow from the Facility 400 into the cavern 444 or fluid may flow from the cavern 444 to another cavern or a pipeline as indicated by the bi-directional flow arrows. A second well 446 connects second salt cavern 448 with the Facility 400. Fluid may flow from the Facility 400 into the cavern 448 or fluid may flow from the cavern 448 to another cavern or a pipeline as indicated by the bi-directional flow arrows. A third well 450 connects third salt cavern 452 with the Facility 400. Fluid may flow from the Facility 400 into the cavern 452 or fluid may flow from the cavern 452 to another cavern or a pipeline as indicated by the bi-directional flow arrows. A fourth well 454 connects fourth salt cavern 456 with the Facility 400. Fluid may flow from the Facility 400 into the cavern 456 or fluid may flow from the cavern 456 to another cavern or a pipeline as indicated by the bi-directional flow arrows. The Facility 400 contains at least one salt cavern, but will

typically contain two to five individual caverns. Four salt caverns are shown here solely for illustrative purposes.

[0116] Each of these salt caverns, 444, 448, 452 and 456 are in fluid communication with the other caverns in this Facility and the pipelines 436 and 438. This fluid communication is achieved through the first manifold 428, the second manifold 440, the piping 430, 432 and 434 and the wells 442, 446, 450 and 454. Various valves and other control mechanisms, not shown allow operators to control the flow of fluids in the Facility 400.

[0117] The LNG source 414 is connected via piping 470 to a high pressure cryogenic LNG pump 56. The LNG source 414 is sometimes simply referred to as "a source of second fluid." The LNG itself is sometimes simply referred to as "the second fluid." The pump 56 raises the pressure of the LNG to dense phase as previously discussed concerning Fig. 9. Piping 472 connects the pump 56 to the LNG heat exchanger 473. The heat exchanger 473 could be the Bishop Process™ Heat Exchanger 62 if the LNG source was on shore as shown in Fig. 1 or the heat exchanger 473 could be the Bishop Process™ Heat Exchanger 220 if the LNG source was offshore as shown in Fig. 4. The heat exchanger 473 warms the second fluid to temperatures that

are compatible with a salt cavern, as previously explained. Piping 474 connects the heat exchanger 473 with an optional booster compressor 476. Piping 478 connects the optional booster compressor 476 with the inlet 426. In this manner, the LNG source 414 is in fluid communication with the pipelines 436 and 438 and the salt caverns 444, 448, 452 and 456. Likewise the pipeline natural gas source is in fluid communication with the pipelines 436 and 438 and the salt caverns 444, 448, 452 and 456. The pipelines 436 and 438 connect the Facility 400 with a market for natural gas, not shown.

[0118] A vaporizer 260 that has been modified to work at dense phase pressures (typically 1,000 psi and above) is connected to the LNG pump 56 via piping 479. Dense phase LNG from the pump 56 is heated in the vaporizer 260, as previously explained, to temperatures compatible with a salt cavern. Piping 480 connects the vaporizer 269 with an optional booster compressor 482. Piping 484 connects the optional booster compressor 482 with the inlet 426. In this manner, the LNG source 414 is in fluid communication with the salt caverns and the pipelines 436 and 438.

[0119] Many pipelines in the U.S. regulate the Btu content of the

natural gas that is delivered to customers. This enables users of natural gas to plan and operate their facilities with predictable results. For example, some pipelines set 1050 Btu per standard cubic foot as a standard for delivered gas. If a bakery sets burners in bread baking ovens for the pipeline standard and the delivered gas actually has a Btu content of 1100 Btu per standard cubic foot, then the top of the bread might burn. This has been a challenge for LNG that is delivered from different parts of the world. For example, Algeria is known to have rich gas that may hit 1200 Btu per standard cubic foot. Other parts of the world, such as Trinidad have lean gas that may dip to 1140 Btus per standard cubic foot. In order to deliver gas to a pipeline standard, LNG importers have sometimes had to adjust their Btu content. This may require pumping air to pipeline pressure in order to reduce the Btu content of the gas. The cost for pumping the air increases operating expenses.

[0120] The Flexible Natural Gas Storage Facility 400 provides an easy and cost effective solution to Btu variances. One solution is to commingle rich gas and lean gas in the same salt cavern to achieve the Btu level required by the pipeline. Another solution is to put rich gas in a first salt

cavern and lean gas in a second salt cavern. When it is time to deliver gas to a pipeline, some rich gas can be blended with some lean gas in a manifold or other piping system prior the delivery to the pipeline to achieve the Btu level required by the pipeline.

[0121] Because the Flexible Natural Gas Storage Facility 400 has access to multiple sources of natural gas, it has economic advantages over both conventional single source salt cavern storage facilities and conventional LNG receiving terminals. In the past 20 years, some conventional LNG receiving terminals in the U.S. have ceased operations due to low demand. This represents a large capital investment that is not being utilized. The Flexible Natural Gas Storage Facility 400 overcomes this market risk because it has access to multiple sources of natural gas. In periods where there is little or no LNG being imported into the U.S., the Facility 400 would still have economic value and activity because it could receive natural gas from a pipeline source and function as a natural gas storage facility. In periods where there are large amounts of LNG being imported into the U.S., the Facility 400 would have economic value and activity because it could be used primarily for receiving, storing and distributing natural gas from a LNG

source. To applicant's knowledge, there is no multi-source natural gas salt cavern storage facility like the Flexible Natural Gas Storage Facility 400.

[0122] EXAMPLE #4

[0123] This hypothetical example is designed to give broad operational parameters for the Flexible Natural Gas Storage Facility 400 as shown in Fig. 11.

[0124] When the LNG source for the Flexible Natural Gas Storage Facility 400 is a cold fluid transport ship 48 offloading at a dock with a land based Bishop Process™ Heat Exchanger, then previous Example 1 is relevant. When the LNG source for the Flexible Natural Gas Storage Facility 400 is a cold fluid transport ship 48 moored to an offshore facility with an offshore Bishop Process™ Heat Exchanger, then previous Example 2 is relevant. In a typical situation, the high pressure LNG pump raises the pressure of the LNG to cavern pressure. The Bishop Process™ Heat Exchanger then warms the fluid to a temperature that is compatible with the salt cavern, typically about 40°F. The optional booster compressor may be necessary to replace pressure lost due to pipeline friction or pressure drops due to distance or pipeline sizing between the LNG pumps and the caverns. When a vaporizer is used with a LNG

source, instead of a Bishop Process™ Heat Exchanger, then previous Example 3 is relevant. The high pressure LNG pump raises the LNG to cavern pressure. The vaporizer then heats the fluid to a temperature that is compatible with the salt cavern, typically to about 40°F. The optional booster compressor may be necessary to replace pressure lost due to friction, pipeline sizes, or distance from the vaporizers and the caverns.

[0125] Although not preferred, the Facility 400 could receive LNG from surface mounted tanks of a conventional LNG receiving terminal such as that currently in operation south of Lake Charles, Louisiana.

[0126] When receiving natural gas from a pipeline natural gas source, the Facility 400 compresses gas from the pipeline to cavern pressure and raises the temperature of the gas to about 200°F. The gas is then cooled in a conventional heat exchanger to about 140°F or less and is injected into a salt cavern. In this example the gas from the pipeline natural gas source is raised to dense phase pressures, but this is not essential to the invention. All that's essential is that the gas be raised to sufficient pressure to be injected into the salt cavern. The facility 400, for example would have connections to one or more pipeline sources of nat-

ural gas. The facility 400 would have valving, piping, control, and measurement capability to both receive gas from the pipelines and deliver gas to the pipelines. This capability is sometimes called a bi-directional capability.

[0127] The Gas Compressor 418 could be a positive displacement or a centrifugal type compressor and would have sufficient capacity and horsepower to raise the pressure received from the Pipeline Natural Gas Source 412 from about 1000 psi to the pressure necessary to inject into the caverns 444, 448, 452, 456 or about 2000 psi. The cavern injection pressures are determined by the design of the caverns but the volume of injection or rate at which gas can be injected into the caverns are determined by the compressor design and horsepower. For this example it is assumed that the cavern injection design rate is 300 million cubic feet of gas injected per day up to the maximum operating pressures of the caverns. This injection rate would require about 25,000 horsepower of compression.

[0128] The compressed gas discharged from the compressor would be at 2,000 psi and about 200 Degrees F and piped to the Conventional Heat Exchanger 422 for cooling before injection into the caverns. For this example the Conventional Heat Exchanger 422 would be a fin-fan type and

designed to cool the compressor discharge from about 200 Degrees F to under 120 Degrees F for injection into the caverns. No further processing would occur with the gas prior to cavern injection. Controls and valving would direct the gas into the appropriate cavern(s). If blending of the pipeline natural gas sourced gas was to be done in the cavern with gas from the second source for BTU control it would be so directed into the cavern(s) designated and operated for in-cavern blending.

[0129] Discharge from the caverns to the Pipeline(s) 436, 438 would be by positive pressure differential as described in examples 1,2, and 3. unless blending of the gas dis-charged from the caverns would be done at discharge in-stead of in the caverns. In that case, the well discharges would be controlled from the appropriate caverns so as to proportion the flow to achieve the BTU content desired in the blended stream. For example, if the desired flow to the pipelines was 600 million cubic feet per day of natural gas that could not exceed 1050 BTUs per cubic foot. If cavern 444 had gas stored in that contained 1100 BTUs per cubic foot and cavern 448 had gas stored in it that contained 1000 BTUs per cubic foot the discharge from each of the caverns could be controlled at 300 million cu-

bic feet per day, blended in the manifold 430, 428, 434 and discharged to the pipelines 436, 438 as 600 million cubic feet per day of 1050 BTU per cubic foot natural gas.

[0130] When discharging from the cavern(s) 444, 448, 452, 456, each cavern could discharge to the manifold in excess of 500 million cubic feet per day using positive pressure differential to the pipeline(s) 438,436, as described earlier. This enables the facility 400 to flow to the pipeline(s) as much as 2 billion cubic feet per day if necessary. There are no LNG liquid tank based receiving and storage facilities in the U.S. that have the capability to deliver natural gas to the pipeline system at rates as high as 2 billion cubic feet per day. This assumes that the pipeline(s) are capable of receiving gas at these high volumes. Between the wells and the pipeline(s) would be valves and controls to control pressure, volumes, and flow rates as necessary and well known to those schooled in the art of salt cavern natural gas storage.

[0131] In addition, dehydration equipment may be used to reduce or remove moisture in the gas that may be picked up in the cavern(s) also well known to those schooled in the art of salt cavern natural gas storage.

[0132] Thus, the Flexible Natural Gas Storage Facility would have

the capability to receive either fluid and from storage discharge the combined fluids to the pipeline(s) at rates significantly higher than a conventional LNG liquid tank based receiving and storage terminal.